Unitil
Unitil Service Corp.

June 22, 2005

VIA OVERNIGHT MAIL

Ms. Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd floor
Boston, MA 02110

Re: Investigation by the Department Regarding Service Quality Guidelines Established in Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 04-116

Dear Secretary Cottrell:

Enclosed for filing on behalf of Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), please find an original and one (1) copy of Unitil's responses to the Department's third set of information requests to all Electric Local Distribution Companies in the above-referenced docket. As requested, copies of Unitil's responses are being sent by e-mail to the parties.

Thank you for your attention to this matter.

Sincerely,

Gary Epler

Enclosure

cc: Jody M. Stiefel, Hearing Officer

Gary Epler
Senior Attorney

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Commonwealth of Massachusetts
Department of Telecommunications and Energy
Investigation Into Service Quality Guidelines
Docket No: D.T.E. 04-116
Department Staff's Third Set of Information Requests to
All Electric Local Distribution Companies

Request No. DTE-LDC 3-1

Refer to Order Instituting Safety Standards, New York Public Service Commission Case 04-M-0159 (January 5, 2005). Please comment on the feasibility of implementing a stray voltage performance measure similar to that described in Attachment A of the above order, with an annual inspection performance target of 95 percent of those facilities scheduled to be inspected during a particular year. The performance measure would have a penalty feature similar to that applied to odor call response for gas distribution companies, such that for each percentage point that an electric distribution company's performance falls below a benchmark of 95 percent, the electric distribution company would be assessed a penalty equal to 25 percent of the total penalty allocated to the stray voltage standard. The maximum penalty for this SQ measure will be incurred at a performance level of 91 percent.

Response:

Unitil has some concerns about implementing a stray voltage performance measure similar to that described in Attachment A of the New York Public Service Commission Case 04-M-0159 (January 5, 2005). Unitil understands and supports the overall goal of ensuring public safety. However, implementing such a requirement on utility owned equipment will be difficult and costly to implement. Implementation of this type of requirement should be well thought out prior to developing a scope, schedule and goals. Unitil has broken down this response into non-utility owned equipment and utility owned equipment for clarification in the response.

Unitil would like to take this opportunity to reiterate that the use of "stray voltage" in the context it is being used is not technically correct. Stray voltage can result from proper distribution system operation. Until suggests that the terms "elevated" or "errant" voltage (i.e. voltage present where it should not ordinarily exist) better describe the issue that the Department is inquiring about.

Non-Utility Owned Equipment:

Section 3 of Attachment A of the New York Public Service Commission Case 04-M-0159 (January 5, 2005) defines the stray voltage testing expectations. Attachment A specifies that the utility is responsible for testing *"all electric facilities that are capable of conducting electricity and are publicly accessible"*. In reading the document it appears that in New York, it is now the utility's responsibility to test not only their equipment, but also customer and municipal owned equipment. Unitil believes this is an unreasonable requirement.

Unitil is defining non-utility owned equipment as all electric facilities and equipment that is owned by customers, municipalities, utilities other than Unitil or companies who may have installed equipment for customers (i.e., emergency generator installations). Non-utility owned equipment can include but are not limited to: streetlights, manholes, secondary hand holes, generators, risers, poles, transformers, substation fences, sectionalizing cabinets, switchgear, reclosers, switches, pedestals, or any other overhead or underground equipment that may be accessible to the public.

Unitil has several concerns associated with testing customer or municipally owned equipment. First, Unitil does not keep records on all non-utility owned equipment. This is an impossible task. Unitil knows where they provide service to each of its customers. From there, a customer (which may be a municipality, other utility or other company which owns electrical equipment) may have an entire distribution system serving their campus. The utility should not be required to keep an inventory of non-utility owned equipment. That would require a new system to track the specifics of customer equipment and somehow transfer that information into a GIS system that field personnel could use during the inspection and testing process. It would also require every municipality, customer, or other company who owns electrical equipment to notify Unitil every time a change is made to their system. This is an impractical expectation.

Second, Unitil is not kept informed as to what type of inspection, testing and maintenance that customers have done on their facilities. Unitil has a safety practice of not opening or operating customer equipment because we are not certain that customers are maintaining their equipment to the same level that we maintain our equipment. Unitil recommends to the customer to hire qualified personnel whenever their equipment needs to be opened or operated. For that reason, it would go against Unitil practice to inspect customer equipment.

Third, Unitil agrees that any utility owned facility for which the testing device indicates the presence of voltage shall be guarded until the situation is remedied. Unitil does not feel it is reasonable for the utility to be given the responsibility of taking corrective action irrespective of the ownership of the equipment. The customer should have responsibility for inspecting, testing and maintaining their equipment. It should not become the responsibility of the utility to inspect and test these facilities.

Fourth, Unitil has an agreement with Verizon for pole set location throughout the service territory. On average, Unitil owns and maintains one-half of the pole plant and Verizon owns the other half of the pole plant. Unitil does not inspect Verizon pole plant. That would increase the quantity of inspections by 50%. The resource impact of this requirement has not been calculated due to the timeliness of this request.

Most of the streetlights in the Unitil service territory are cobra-head style mounted on wood poles. However, ornamental lighting is predominantly owned by the towns or other customers. Unitil does not know the locations of all of the streetlights and would not know if a streetlight was removed unless notified by the owner. This approach to testing will not find the locations where someone has removed a light and simply buried the

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wires. Once Unitil is informed that a light is removed, the wire is either removed or cut in the manhole.

Utility Owned Equipment:

Unitil is defining utility owned equipment as the electrical facilities and equipment owned by Unitil. Utility owned equipment can include but is not limited to: streetlights, manholes, secondary hand holes, generators, risers, poles, transformers, substation fences, sectionalizing cabinets, switchgear, reclosers, switches, pedestals, or any other overhead or underground equipment that may be accessible to the public.

Unitil has an Operations Bulletin which defines the extent of Distribution Inspections on the Unitil system. See DTE-LDC 3-1, Attachment A - *OP6.00 Distribution Inspections*. This bulletin defines the following schedule for inspections:

Annual Inspection
- Underground Network or Primary Distribution System – a visual inspection to be performed annually.

Five-Year Public Safety Inspection
- Underground Distribution Facilities – A visual safety inspection of underground equipment to be performed every five years.

Ten-Year Public Safety Inspection
- Overhead Distribution – A visual safety inspection of overhead distribution systems to be performed every ten years.

Ten-Year Pole Test - Distribution pole test to be performed every ten years.

The Annual Inspection on the Underground Network or Primary Distribution System is referring to the underground system in the Downtown Fitchburg Area. This is a high pedestrian traffic area. The Operations Bulletin requires that every manhole and vault is inspected on an annual basis. This inspection includes a voltage test prior to entering the manhole or vault. For the utility owned equipment in this portion of the system, Unitil would not have a problem meeting the requirements as described in Attachment A of the New York Public Service Commission Case 04-M-0159 (January 5, 2005).

The Five Year Public Safety Inspection of Underground Distribution Facilities is a visual inspection of all Unitil owned underground facilities throughout the service territory. This inspection does not include any voltage measurements. The resource impact of adding the voltage testing requirement has not been calculated due to the timeliness of this request.

The Ten Year Public Safety Inspection of Overhead Distribution Facilities is visual inspection of all Unitil owned overhead facilities throughout the service territory. This inspection does not include a voltage test and it is not completed in a five year timeframe. The reduction in schedule from ten years to five year would require a significant increase in resources. In addition, a voltage test would have an effect of increasing the time per location which will have an overall impact of lengthening the schedule.

The ten year pole test is simply a condition test on each wood distribution pole that Unitil owns. This is used to develop a condemned pole listing which is prioritized on an annual basis for replacement.

In general, Unitil does not have every piece of equipment identified in a geographical representation that field personnel could use for testing. The Unitil mapping system identifies significant field equipment such as: poles, wires, transformers, fuses, switches, etc... The mapping system does not identify all of the facilities where voltage may be present such as: pole grounds, guy wires, riser conduits, streetlights, etc... In order for Unitil to be certain that it is testing all of the electrical facilities that may be accessible to the public, a complete and detailed survey would be required of the entire service territory. This survey would need to capture the location each piece of equipment and plot the information in a geographical manner for field use. This would be a large project that would take some time to complete. The resource impact of adding the voltage testing requirement has not been calculated due to the timeliness of this request.

Conclusion:

One of Unitil's primary goals is to ensure public and personnel safety. Unitil has not experienced any problems with "errant", "elevated" or "stray" voltages within its service territory. Unitil believes that the approach as defined in Attachment A of the New York Public Service Commission Case 04-M-0159 (January 5, 2005) is an overly aggressive approach which places an unreasonably high responsibility on the utility. Unitil believes that the actual costs associated with implementing this requirement have not been well thought out and documented in New York. The costs associated for Unitil to implement this requirement would be significant. However, Unitil did not have enough time to develop an estimate for implementing this requirement due to the timeliness of this request.

It is unreasonable for utilities to have the responsibility for testing all electric facilities regardless of ownership. Unitil does not know where all of the non-utility facilities are located. Unitil does not know the inspection, testing and maintenance history of the equipment and therefore would recommend the customer hire qualified personnel work with the equipment. The customer is responsible for maintaining that equipment to ensure safe and reliable operation. This is not the utility's responsibility.

Unitil would propose further study on this topic. The overall impact of such a requirement is not known at this time. Before Unitil can consider developing a performance target for this requirement, the actual impact to the utility and the customer needs to be fully documented. Then a determination can be made as to the scope, schedule and goals of the requirement. With the existing resources, Unitil would find it very difficult if not impossible to meet the requirements as defined in Attachment A of the New York Public Service Commission Case 04-M-0159 (January 5, 2005).

Further study on this topic may result in an approach that is more reasonable and economical to implement. For instance, it may be advisable to implement a random sampling approach to testing. The utility would randomly select areas throughout the system to test. The results of the sample would determine if more testing was required. This would reduce the resource requirement, while still implementing a testing requirement.

Unitil would also like to point out that the requirement in Attachment A of the New York Public Service Commission Case 04-M-0159 (January 5, 2005) will not identify all areas where "elevated" or "errant" voltage is present. As stated previously, unless the utility knows that a customer of the town has removed a streetlight, the utility will not know to disconnect the power.

Person Responsible: Kevin Sprague **Date:** June 22, 2005

Unitil

Operations Bulletin #OP6.00

SUBJECT: Distribution Inspections
EFFECTIVE: 04/01/05

ISSUED BY: G. Appleton
CONTENT TEAM: C. Dube, G. Appleton, D. Nudd

1.0 PURPOSE

- To provide a uniform method for maintaining and inspecting overhead and underground distribution systems
- To ensure compliance with applicable regulatory requirements
- To ensure the integrity of the poles and equipment
- To ensure the safe operation of the distribution system
- To establish requirements for record keeping and performance measures

2.0 SCOPE

These maintenance guidelines apply to the electric distribution systems and provide the framework for a structured inspection and reporting process. In addition, it is the responsibility of all employees, in the everyday course of their work, to promptly report any abnormalities of the electric distribution system which may compromise public safety or the integrity of the system.

3.0 MAINTENANCE – FREQUENCY AND CATEGORY SUMMARY

Annual Inspection

- Underground Network or Primary Distribution System – a visual inspection to be performed annually.

Five-Year Public Safety Inspection

- Underground Distribution Facilities – A visual safety inspection of underground equipment to be performed every five years.

Ten-Year Public Safety Inspection

- Overhead Distribution – A visual safety inspection of overhead distribution systems to be performed every ten years.

Ten-Year Pole Test - Distribution pole test to be performed every ten years.

4.0 FREQUENCY AND CATEGORY DESCRIPTIONS

4.10 Semi- Annual Inspection (Manhole System)

A visual Inspection of all exposed components located in a manhole and/or vault shall be made at least once a calendar year. In conjunction with the visual inspection a comparative temperature check will be performed on all connections.

- The visual inspection shall consist of an examination of the condition of the electrical system, equipment, tagging, and the interior of the structure.
- Annually, preferably during circuit peak periods, a comparative heat check between phases will be performed on all connections. Heat checks may be conducted more often depending upon the load characteristic of the circuit.
- Manholes and/or vaults may be checked more often for water problems depending upon rainfall or melting snow.

4.20 Five-Year Public Safety Inspection (Underground Distribution Facilities)

A public safety inspection of company owned underground equipment shall be performed on a five-year cycle because of the proximity and accessibility to the public. A visual observation of above-grade equipment shall identify any potential public safety concerns, as well as conditions affecting service and reliability.

- Signage
Warning signs/decals shall be in place on all fences, above-grade secondary splice boxes and pad mounted equipment including transformers, sectionalizers and switching cabinets.

- Security
Padlocks, one time locks and penta head locking bolts, where provided for shall be installed and used on all secondary splice boxes and pad-mounted equipment.

- Condition

  The condition of the pad, pad-mounted equipment and secondary splice boxes shall be observed with particular attention paid to location of the equipment on the pad, the grade level surrounding the pad, and the general physical condition of the unit.

Specific attention shall be noted to the following items:

- Properly alignment on pad.
- No holes
- Free of rust
- No visible oil leaks
- No excessive gap or spaces in cabinet doors.
- Proper clearance from buildings, roads, fences.
- Traffic barriers in place if required.
- Proper vegetation clearance.

4.30 Ten-Year Public Safety Inspection (Overhead Distribution Facilities)

Overhead distribution facilities shall be visually inspected every ten-years to identify potential failure, deterioration of construction, unsafe conditions or possible public safety hazards.

Specific attention shall be noted to the following Items:

- Wires' passing through trees to the extent that someone working in, or climbing the tree, might be unaware of the presence of the wires.
- Low or overhanging wires, in areas that could contact or be contacted by buildings, ladders, vehicles, etc.
- Damaged or deteriorated equipment such as cross-arms, insulators, terminators, etc.
- Climbing steps or standoff brackets on poles located lower than eight (8) feet above grade or the nearest surface from which climbing would commence.
- Construction activity, which might encroach on areas, occupied by company facilities or changes in the use of land, roads, or buildings.
- Massachusetts Department of Public Works requires that utility poles adjacent to state maintained highways, which are located within six (6) feet of the edge of a traveled way, and not protected by guardrails will have reflective markers mounted on or attached to the pole. The reflector will be located on the pole in such a manner that they are visible to on-coming traffic.
- Foreign attachment to Company equipment that would cause potential danger to the public or Company personnel.

4.40 Ten-Year Pole Test

On a ten-year cycle, wood distribution poles in the DOC's maintenance area shall be visually inspected and tested at and below grade level to determine the soundness of the wood.

Wood Pole Maintenance Procedures

The purpose of this section is to identify destructive forces that affect wood poles. The following outlines a replacement program based on periodic tests to confirm the presence and determine the degree of the decay.

Destructive Forces

One of the most destructive forces affecting wooden poles is decay. It will generally progress at a predictable rate and its advance can be readily diagnosed in the field at all but the very early stages. Detection of decay or damage is essential in establishing the remaining pole life.

Types of Decay

Internal Decay

Internal deterioration of treated poles is due very largely to development of checks after treatment that exposes the untreated center portion of the pole to fungi and insects.

External Decay

External Decay results from using poor preservative or from a low absorption of the preservative by the timber. In older poles, external decay is a consequence of gradual loss of most of the preservative in the sapwood through leaching, evaporation, and chemical change. In butt-treated cedar poles, a softening of the sapwood known as "shell rot" occurs in the upper untreated portion of the pole. Such decay starts in the inner sapwood where air and moisture conditions promote fungus growth, and eventually extends to the outer sapwood.

Groundline Decay

In most cases, the first occurrence of decay will be just below the groundline. This is where the conditions of moisture, temperature, air, and the absence of direct sunlight are most favorable to the growth of fungi. This is a portion of the pole usually hidden from view and it is close to the natural breaking point of a pole under strain. This is the most critical part of the pole and warrants special inspection.

Detection of Decay

Two methods are generally used to determine the presence and the degree of decay in poles. Sounding a pole with a hammer, mechanical sounding tool, or electronic sonic pole tester will usually detect the presence of decay. Boring the suspect pole with a brace and bit or an increment borer will confirm the presence and determine the degree of the decay.

Determining the Serviceability of Decayed Poles

The decision to replace a decayed pole shall depend upon the remaining strength of the pole. The permissible reduced circumference of a pole is a good measure of serviceability.

Pole Circumference Safety Factors

Wood pole lines are designed using pole strength safety factors. For this bulletin, the groundline circumference of the pole will be used as a measure of pole strength. Table 1 shows the relationship between new pole circumferences, and reduced circumferences. Circumference reductions to compensate for other categories of decay, as shown in table 2, 3, and 4 should be applied to the circumferences in table 1 to determine the resultant reduced circumference.

If the reduced circumference is less than, or equal to the replacement circumference, the pole should be replaced.

5.0 <u>RECORD KEEPING</u>

The results of all cycle inspections and tests and corrective action taken shall be recorded, and retained for one complete cycle but not less than a period of six (6) years. Appropriate measures shall be taken on a timely schedule to correct any defects and/or deficiencies found on test or inspections. Inspection forms shall identify all poles/transformers visited. All non compliant findings shall be noted indicating corrective action to be taken and close out date (i.e., when corrective action was completed)

5.10 Forms

Forms to be used for inspection and record keeping purposes are included as Attachments A, B, and C.

6.1 PERFORMANCE MEASURES

6.10 Overview

Performance measures are intended to provide the means to monitor performance with respect to this guideline. The performance measures fall under three general categories, Plan and Progress Reporting, Effectiveness Metrics, and Efficiency Metrics.

Each DOC shall report the performance measures monthly. A quarterly Unitil System Summary shall consist of a consolidation of all three DOCs.

The following accounts shall be utilized for budgeting and tracking related cost and provides the data source for the Efficiency Metrics.

583.05	Overhead Dist. – Non-Maint. Area	OH Inspection cost - Unitil
583.06	Overhead Dist. – Maint. Area	OH Inspection costs – non-Unitil maint.
584.04	Underground Equip. Inspections	Underground Inspection costs

6.20 Plan and Progress Reporting

By January 1 of each year each DOC shall specify planned cycle inspection and pole testing work for the year. For each inspection category, the "Number in Service" shall also be updated as required.

Each month the actual work completed for each cycle inspection shall be reported and an indication of work schedule accuracy shall be calculated.

The following inspection categories shall be reported:

Manhole System Inspections
Underground Distribution Device Inspection
Overhead Distribution Inspection + Pole Test
(for Unitil maintenance area)
Overhead Distribution Inspection
(for non-Unitil maintenance area)

6.30 Effectiveness Metrics

One effectiveness metric for distribution inspections shall be reported – the **Pole Test Reject Rate**. This metric is tied to Pole Testing (Unitil maintenance area) and requires the number of poles rejected per test be reported monthly.

6.40 Efficiency Metrics

The efficiency metrics for distribution inspections shall be as follows (requires monthly reporting of costs):

Underground Device Inspection - Cost per Device

Pole Inspection + Test – Cost per Pole
(Unitil maintenance area)

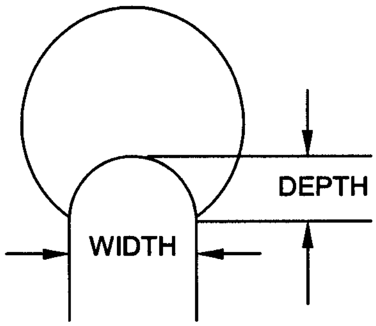
Pole Inspection – Cost per Pole
(Non-Unitil maintenance area

Table 1 – Pole Testing Table
Replacement based on remaining circumference at ground line

08/09/01

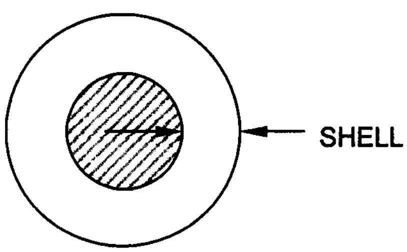
Pole Circumference (Installed)	Douglas Fir & Southern Yellow Pine		Western Red Cedar	
	Transmission	Distribution	Transmission	Distribution
30	21.4	23.8	19.5	21.6
31	22.2	24.6	20.1	22.4
32	22.9	25.4	20.8	23.1
33	23.6	26.2	21.4	23.8
34	24.3	27.0	22.1	24.5
35	25.0	27.8	22.7	25.2
36	25.7	28.6	23.4	26.0
37	26.4	29.4	24.0	26.7
38	27.2	30.2	24.7	27.4
39	27.9	31.0	25.3	28.1
40	28.6	31.7	26.0	28.8
41	29.3	32.5	26.6	29.6
42	30.0	33.3	27.3	30.3
43	30.7	34.1	27.9	31.0
44	31.4	34.9	28.6	31.7
45	32.2	35.7	29.2	32.5
46	32.9	36.5	29.9	33.2
47	33.6	37.3	30.5	33.9
48	34.3	38.1	31.2	34.6
49	35.0	38.9	31.8	35.3
50	35.7	39.7	32.5	36.1
51	36.4	40.5	33.1	36.8
52	37.2	41.3	33.8	37.5
53	37.9	42.1	34.4	38.2
54	38.6	42.9	35.1	38.9
55	39.3	43.7	35.7	39.7
56	40.0	44.4	36.4	40.4
57	40.7	45.2	37.0	41.1
58	41.4	46.0	37.7	41.8
59	42.2	46.8	38.3	42.5
60	42.9	47.6	39.0	43.3
61	43.6	48.4	39.6	44.0
62	44.3	49.2	40.3	44.7
63	45.0	50.0	40.9	45.4
64	45.7	50.8	41.6	46.2
65	46.5	51.6	42.2	46.9
66	47.2	52.4	42.9	47.6
67	47.9	53.2	43.5	48.3
68	48.6	54.0	44.2	49.0
69	49.3	54.8	44.8	49.8

Table 2
Reduction in measured circumference of pole to compensate for external pocket



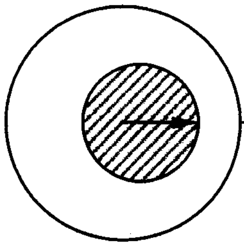
Width of pocket (inches)	1					2					3					4					5					6				
Depth of pocket (Inches)	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
Measured circumference Of pole (inches)	Reduction in circumference (inches)																													
30 to 40	1	1	1	2	2	1	2	2	3	3	2	3	4	4	4	2	4	5	5	6	3	5	6	7	8	5	7	8	9	10
40 to 50	1	1	1	2	2	1	2	2	3	3	2	3	3	4	4	2	3	4	5	6	3	4	5	6	7	3	5	6	7	8
50 to 60	1	1	1	2	2	1	2	2	3	3	2	3	3	4	4	2	3	3	4	5	3	4	4	5	6	3	4	5	6	7

Table 3
Reduction in measured circumference of pole to compensate for hollow heart



Width of pocket (inches)	3	3 1/2	4	4 1/2
Measured circumference of pole (inches)	Reduction in circumference (inches)			
30 to 40	2	1	0	0
40 to 50	3	2	1	0
50 to 60	4	3	2	1

Table 4
Reduction in measured circumference of pole to compensate
For enclosed pocket



Diameter of pocket (inches)	3			4			5		
Minimum thickness of shell (inches)	1	2	3	1	2	3	1	2	3
Measured circumference of pole (inches)	Reduction in circumference (inches)								
30 to 40	2	1	1	3	1	1	4	2	1
40 to 50	2	1	1	3	2	1	4	3	1
50 to 60	2	2	1	3	3	1	4	3	1

UNITIL MANHOLE / VAULT REPORT

Manhole/Vault #		Account #		Date:

#	Item	Value	N/A	Yes	No
1	Manhole cover voltage check				
2	Oxygen Level (Acceptable range: 19.5 to 25%)				
3	Gas Level (Presence of gas requires ventilation)				
4	Manhole Dry				
5	Sump Pump Working				
6	Vault Lights Working				
7	Vault Outlets Working				
8	Primary Connections Okay				
9	Secondary Connections Okay				
10	Neutrals and Grounds Free of Corrosion				
11	Arcproofing Tape Installed on Primary Cable				
12	Circuit Labels and Tags Okay				
13	Cable Racks Okay				
14	Vac Pac Switches Okay				
15	Manhole Castings, Hatches, etc. Okay				

#	Item	Manual	Auto	Open	Closed
16	Circuit Protectors				
a	Operating Handle Position				
b	Protector Position				

#	Item	Value	Yes	No
c	Protector Okay			
d	Fuse Okay			
e	Counter Reading			
17	Transformers			
a	Record Number			
b	Transformer Okay			
c	Current Temperature			
d	Maximum Temperature			
e	Liquid Level - Main Tank			
f	Liquid Level - Primary Switch Comp.			
18	Primary Switch Okay			
			Open	Closed
19	Primary Switch Position			

20 Check Primary Connection Temperatures:

Location of Temp by Circuit #	Temp	Location of Temp by Circuit #	Temp
A		M	
B		N	
C		O	
D		P	
E		Q	
F		R	
G		S	
H		T	
I		U	
J		V	
K		W	
L		X	

Comments:

Attachment B

UNITIL UNDERGROUND DISTRIBUTION FACILITIES INSPECTION REPORT

Five-Year Public Safety Inspection A visual safety inspection of underground equipment to be performed every five years.							
Date:		**Inspected By:**		**Page**		**of**	
Legend:	**N/A** = Not Applicable, ✓ = Checked OK, **X** = Needs Attention for specific refer to comments / notes						

Town Code	Location	Pole Number	Installed Date	Unit	Primary Voltage	Secondary Voltage	Phase	Type	Switching Cabinet	Decals warning signs	Pad lock / one time locks	Penta head locking bolt	Condition of unit	Aligned properly	No holes	Free from rust	No visible oil leaks	No excessive gap in doors	Traffic Barriers	Vegetation Clearance	Comments / Notes

Attachment C

UNITIL OVERHEAD DISTRIBUTION AND POLE TEST REPORT

Ten-Year Public Safety Inspection & Ten-Year Pole Test

A visual safety inspection of overhead distribution facilities to be performed every ten years.

Date:		Inspected By:		Page		of	
Legend:	N/A = Not Applicable, ✓= Checked OK, X = Needs Attention for specific refer to comments / notes						

Town Code	Location	Pole Number	Year Installed	Plant unit	Class	Type	Vegetation Clearance	Wire Proper Height	Equipment	Pole / Arm	Transformer(s) Condition	Anchor / Guys	Climbing Steps	Reflectors	Foreign Attachments	CATV Auth.	Telephone Auth.	Test	Comments / Notes

Commonwealth of Massachusetts
Department of Telecommunications and Energy
Investigation Into Service Quality Guidelines
Docket No: D.T.E. 04-116
Department Staff's Third Set of Information Requests to
All Electric Local Distribution Companies

Request No. DTE-LDC 3-2

Please refer to Order Instituting Safety Standards, New York Public Service Commission Case 04-M-0159 (January 5, 2005). Assuming the Department were to adopt a stray voltage service quality measure similar to that proposed in Information Request DTE-LDC 3-1, provide a weighting factor that would be considered appropriate to ascribe to such a performance measure.

Response:

As stated in its response to DTE-LDC 3-1, Unitil recommends further study on this topic. The overall impact of such a requirement is not known at this time. Before Unitil can consider developing a performance target or weighting factor for this requirement, the actual impact to the utility and the customer needs to be fully documented. Then, a determination can be made as to the scope, schedule and goals of the requirement.

Person Responsible: Kevin Sprague **Date:** June 22, 2005

Request No. DTE-LDC 3-3

Please comment on the advantages and disadvantages of calculating SAIDI and SAIFI statistics and penalties based on the performance of individual feeder circuits rather than system averages.

Response:

Unitil believes that reporting SAIDI and SAIFI on a system basis provides a high level view of how the system as a whole is performing. Reporting SAIDI and SAIFI statistics by circuit does provide a more granular view on system reliability. However, there are advantages and disadvantages to calculating SAIDI and SAIFI statistics and penalties based upon the performance of individual circuits.

Unitil does not believe it is necessary to implement a reporting requirement and penalties based upon circuit level SAIDI and SAIFI. Unitil does and will continue to use this information as an analysis tool for reliability improvement projects. It appears that the disadvantages to reporting data on circuit level SAIDI and SAIFI truly outweigh the perceived advantages.

Advantages:

Unitil does not presently report SAIDI and SAIFI statistics on a circuit level basis except for the worst performing circuits reporting requirement. Unitil does review each individual circuit on an annual basis to analyze the performance over the past year. This analysis is one tool used by Unitil to compare how the current reliability of a circuit compares to its historical performance. Circuit level reliability cannot be compared between circuits.

This report would provide the Department with a more detailed view on the area reliability as opposed to the overall system view. Once enough information is gathered, the Department may be able to make some determinations on areas of the system where reliability performance may have changed (either positively or negatively). This information may not be useful without knowing the maintenance history of the circuit in question.

Disadvantages:

Unitil's present approach to improving reliability performance is focused on improving the overall system performance. As stated previously, Unitil conducts a formal reliability analysis on each circuit on an annual basis. Potential system improvement projects are developed and estimates calculated for each project. All reliability projects are prioritized based upon a cost per saved customer minute and saved customer interruption basis. The less beneficial projects are eliminated from capital budget consideration. This approach ensures that Unitil is implementing the least cost projects which provide the greatest reliability benefit to the system as a whole. If Unitil was required to develop a penalty measure for each circuit, it will more than likely result in the need to implement smaller projects which have a more localized impact on reliability. These projects will tend to have a higher cost per saved customer minute and saved customer interruption basis. This requirement will eliminate the flexibility for utilities to develop projects that provided the greatest benefit from a cost and reliability standpoint.

Unitil wants to reiterate the point that each circuit is different. Each circuit has its own design, customer density, location (rural or urban, trees or not), circuit ties, etc... From this standpoint, circuits cannot be compared within a utility or with neighboring utilities. Circuits can only be compared to its historical performance, and even this comparison is not necessarily straight-forward.

Circuit configurations change all of the time. Circuit configurations are a good way to maximize system performance from a reliability standpoint while also deferring system improvement projects for loading or voltage concerns. Once the configuration of a circuit changes, the overall performance of the circuit will change and can no longer be compared with its historical performance.

The SAIDI and SAIFI reliability indices alone do not always provide an accurate picture of the reliability performance of the circuit. For instance, assume a circuit is serving one customer. Over the past five years, this circuit has not experienced any outages. This year, the circuit has one, 3-hour outage. This results in a SAIDI of 180 minutes and a SAIFI of 1.0. If this is compared to historical performance, a SAIDI of 180 minutes is very poor, although this customer's actual experience is rather good reliability. Simply looking at SAIDI and SAIFI calculations can provide a misrepresentation of the reliability performance.

Most of Unitil's circuits are rural and are affected by tree contact. Unitil has a documented vegetation management bulletin which defines the tree trimming cycle based upon voltage class. It is reasonable to believe that circuits that have just been trimmed will have fewer tree related interruptions than circuits that have not recently been trimmed. Therefore, over the course of the trimming cycle, reliability will be impacted by the number of years since the last trimming. Reviewing reliability on a circuit level will capture this variability making it difficult to set appropriate circuit level targets.

Overall, Unitil believes that calculating reliability indices at a circuit level is a good analytical tool that can be used by the utilities, in conjunction with other system knowledge, to develop system reliability improvement projects. However, setting penalty levels on a circuit basis may adversely influence the flexibility that utilities require to implement reliability improvement projects according to the most favorable cost-to- benefit ratio. In addition, annual variability in circuit level reliability performance will make it very difficult to set realistic performance goals.

Person Responsible: Kevin Sprague **Date:** June 22, 2005

Commonwealth of Massachusetts
Department of Telecommunications and Energy
Investigation Into Service Quality Guidelines
Docket No: D.T.E. 04-116
Department Staff's Third Set of Information Requests to
All Electric Local Distribution Companies

Request No. DTE-LDC 3-4

Please comment on the advantages and disadvantages of making CAIDI and CAIFI penalty measures.

Response:

Customer Average Interruption Duration Index (CAIDI) is the average interruption duration for those customers who experience interruptions during the year. It can also be interpreted as the average time required to restore service. It is calculated by dividing the annual sum of all customer interruption durations by the total number of customer interruptions.

Customer Average Interruption Frequency Index (CAIFI) is the average number of sustained interruptions for those customers who experience interruptions during the year. It is calculated by dividing the total annual number of customer interruptions by the total number of customers affected by interruptions. In determining the total number of customers affected, each customer is counted only once regardless of the number of customer interruptions that the customer may have experienced during the year.

At the preset time, Unitil provides CAIDI information in its annual Service Quality Report. SAIDI can be calculated by multiplying the SAIFI and CAIDI indices. SAIDI can be affected by changes in CAIDI and CAIFI in two ways: by either taking measures to shorten the length of the outage, or by taking measures to avoid the interruption altogether. By setting CAIDI and CAIFI penalty measures, however, the flexibility that the utilities require, as well as the incentive, to implement the most cost effective reliability improvements may be affected, possibly in an adverse or unintended manner.

Advantages:

The obvious advantage to reporting on CAIDI and CAIFI is that the Department would receive a high level view of how long it is taking to restore power and how outages are affecting the group of customers that are having outages. CAIDI is already provided on an annual basis. Whether it is specifically provided or calculated from SAIDI and SAIFI, it provides the response time analysis that is missing from the SAIDI and SAIFI calculations.

By reporting CAIDI, it does not allow the utility to mask poor response time performance with less frequent outages. This would provide the Department with a tool for evaluating each operational area.

Disadvantages:

There are several disadvantages to adopting CAIDI and CAIFI as penalty measures. First, CAIDI can vary greatly depending on where the outage is located. The farther the outage is located from the source, the longer it takes to restore the power. CAIDI is also affected by time of day. Generally, the CAIDI during working hours should be less than CAIDI during off hours.

CAIDI is also affected by the design of the system. If the system has redundancy built in and has automated or semi-automated circuit ties, that will help reduce the overall CAIDI calculation. However, it is not necessarily prudent to design the system with 100% redundant capacity simply to reduce the restoration time.

CAIDI can also be affected by the average number of concurrent events. In general, the crew compliment is fixed for Unitil. During large events where it is determined that the fixed crew compliment for Unitil cannot manage the size of the event, Unitil will obtain more crew resources from the other Unitil companies and contractors. During large events where there are multiple outages occurring at the same time, CAIDI tends to increase. Generally, these large events are caused by abnormal weather conditions. Therefore, CAIDI can be affected by the number of storms during a single year.

CAIFI can be very difficult to calculate without the assistance of an automated outage management system. The Unitil outage database does not have the ability to accurately identify how many times a single customer has been interrupted in a given timeframe. In order for Unitil to accurately calculate CAIFI, it would require an automated outage management system. The cost of implementing this sort of system is significant, but was not estimated due to the timeliness of these responses.

Conclusion:

CAIDI on its own cannot be used to measure reliability performance. It is only part of the analysis. However, if penalty measures are set for each SAIFI, SAIDI and CAIDI, then it could result in double penalizing the company. For instance, if a company is just below the penalty measure for SAIFI and over the penalty measure for CAIDI, this would result in a SAIDI above the penalty measure. The company would then be penalized for exceeding both the SAIDI and CAIDI measures even though it is for the same reason.

SAIDI continues to be the best reliability measure for gauging how well a system has performed from a reliability standpoint. CAIDI and CAIFI do provide valuable information about response time and how outages are affecting those customers who actually sustain an outage. Implementing CAIFI reporting is very difficult and will result in inaccuracies unless some sort of outage management system is implemented that can measure the reliability of individual customers.

Person Responsible: Kevin Sprague **Date:** June 22, 2005